

REGIONAL HAZE RULE FOUR FACTOR ANALYSIS FOR THE BOISE CASCADE WOOD PRODUCTS MEDFORD PLYWOOD MILL

JUNE 2020

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1. INTRODUCTION

The Oregon Department of Environmental Quality (DEQ) Air Quality Division is in the process of developing a state implementation plan (SIP) revision for the second planning period under the 1999 Regional Haze Rule (RHR) at 40 CFR Part 51, Subpart P. The RHR focuses on improving visibility in federal Class I areas by reducing emissions of visibility impairing pollutants. DEQ is required to update the SIP by July 2021 to address further controls that could be applied to reduce emissions of sulfur dioxide (SO₂), nitrogen oxides (NO_x), and particulate matter less than 10 microns (PM₁₀) for the 2021-2028 period. DEQ has requested that several sources within the state submit a Four Factor Analysis to examine the feasibility of additional emissions controls. This report provides the four factor analysis for the Boise Cascade Wood Products, LLC (BCWP) Medford, Oregon Plywood Mill (Medford Mill).

In accordance with the August 2019 Guidance on Regional Haze State Implementation Plans for the Section Implementation Period, “there is no specified outcome or amount of emission reduction or visibility improvement that is directed as the reasonable amount of progress for any Class I area.”¹ The guidance states that it may be reasonable for a state not to select an effectively controlled source for further measures and provides several examples on pages 23-25, such as sources subject to recently reviewed or promulgated federal standards, sources that combust only natural gas, and sources that are already well-controlled for SO₂ and NO_x. Therefore, this report focuses only on the most significant sources of SO₂, NO_x, and PM₁₀ emissions at the Medford Mill.

This report provides a four factor analysis for SO₂, NO_x, and PM₁₀ emissions from the biomass boilers, veneer dryers, and plywood presses located at the Medford Mill. Emissions from these sources comprise 99 percent of the total site-wide 2017 actual SO₂, NO_x, and PM₁₀ emissions at the Medford Mill. The remaining PM₁₀ emissions from permitted sources are from material

¹ EPA-457/B-19-003, August 2019, “Guidance on Regional Haze State Implementation Plans for the Second Implementation Period.”

handling sources that are already controlled by baghouses or from fugitive sources that emit little PM₁₀, would not disperse widely from the facility, and would not be cost effective to control. For example, if we assume, based on an EPA fabric filter fact sheet², that the annual cost of a fabric filter is \$10 per standard cubic foot per minute (scfm) and if the flow rate from a currently uncontrolled source is only 10,000 scfm, the cost to apply a fabric filter to any source that emits 5 tpy or less of PM₁₀ is at least \$20,000/ton of PM₁₀ reduced, which is not cost effective.

Although the four factor analysis does not include an evaluation of visibility impacts of additional controls, the guidance indicates that states may include an analysis of visibility impacts of potential control measures as part of their determination of whether additional controls should be required for a particular source during the second implementation period. The material handling and fugitive PM₁₀ sources not included in the four factor analysis have small actual emissions (and also small portions of the PM₁₀ plant site emission limit [PSEL]) and are not likely to impact visibility in Class I areas. Emissions from these sources are not likely to travel much further than the facility's fenceline and the air permit requires management procedures to be implemented to control fugitive dust emissions. For example, watering of material handling sources or unpaved roads is performed if conditions are conducive to the potential for fugitive dust being emitted off site.

In accordance with DEQ guidance, insignificant sources are not addressed in this analysis. Sections 2 through 4 provide the four factor analysis for SO₂, NO_x, and PM₁₀ emissions from the Medford Mill biomass boilers, veneer dryers, and plywood presses. Appendix A presents the control cost calculations and Appendix B presents 2017 actual emissions data.

² <https://www3.epa.gov/ttn/catc/dir1/ff-revar.pdf>

1.1 FOUR FACTOR ANALYSIS

Pursuant to 40 CFR 51.308(f)(2)(i), DEQ has requested that the Medford Mill address the following four factors to determine if additional emissions control measures are necessary to make reasonable progress toward natural visibility conditions at Class I areas:

- The cost of compliance
- Energy and non-air quality impacts of compliance
- The time necessary for compliance
- Remaining useful life of existing affected sources

This analysis addresses these factors for additional control options that could be applied to the most significant SO₂, NO_x, and PM₁₀ emission sources at the mill using available site-specific data, capital costs of controls from available analyses for similar sources, and operating cost estimates using methodologies in the U.S. EPA Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual. No site-specific engineering analyses were performed for this study. The analysis relies on readily available information to determine if additional emissions controls may be feasible.

1.2 SUMMARY OF SOURCES EVALUATED AND EXISTING REGULATORY REQUIREMENTS

Table 1-1 provides basic information regarding the Medford Mill sources that were evaluated in detail. The sources evaluated in this report are already subject to regulation under several programs aimed at reducing emissions of conventional and hazardous air pollutants and are well controlled. Biomass boilers and plywood manufacturing operations are subject to National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations, which require the use of Maximum Achievable Control Technology (MACT).

Table 1-1
Summary of Sources Evaluated

Emissions Unit Description	Fuel Fired	Control Technology	Emissions Limits
Biomass Boilers (3) (EU1)	Biomass	Electrostatic precipitator (ESP)	0.015 gr/dscf PM (LAER)
Veneer Dryers (EU2)	NA	Regenerative thermal oxidizers (RTO) 1 and 2	0.30 lb/MSF PM
Plywood Presses (EU3a, 3b)	NA	No add-on controls	0.10-0.15 gr/dscf PM (limits vary by press)

The U.S. EPA developed the RHR to meet the Clean Air Act (CAA) requirements for the protection of visibility in 156 scenic areas across the United States. The first stage of the RHR required that certain types of existing stationary sources of air pollutants evaluate Best Available Retrofit Technology (BART). Specifically, the BART provisions required states to conduct a specific evaluation of existing, older stationary sources that pre-dated the 1977 CAA Amendments and, therefore, were not originally subject to the Standards of Performance for New Stationary Sources (NSPS). The purpose of the program was to identify older emission units that contributed to haze at Class I areas and that could be retrofitted to reduce emissions and improve visibility in these areas. The BART requirement applied to emission units that fit all three of the following criteria:

1. The units came into existence between August 7, 1962 and August 7, 1977;
2. The units are located at facilities in one of 26 NSPS categories; and
3. The units have a total potential to emit (PTE) of at least 250 tons per year (tpy) of NO_x, SO₂, or PM₁₀ from all BART-era emission units at the same facility.

MACT standards that limit visibility-impairing pollutants were determined to meet the requirements for BART unless there were new cost-effective control technologies available. Per Section IV of 40 CFR Part 51, Appendix Y, Guidelines for BART Determinations under the Regional Haze Rules: “Unless there are new technologies subsequent to the MACT standards

which would lead to cost-effective increases in the level of control, [state agencies] may rely on the MACT standards for purposes of BART.” Although the Medford Mill was not subject to BART, it is still relevant that EPA determined that sources demonstrating compliance with MACT are already well controlled for purposes of the RHR. If sources are already well-controlled and not significantly contributing to visibility impacts at nearby Class I areas, further control should not be required to reduce emissions for the second planning period of the RHR.

1.3 SUMMARY OF RECENT EMISSIONS REDUCTIONS

Since 2011, the Medford Mill has made improvements to reduce its emissions. The biomass boilers are subject to the provisions of 40 CFR Part 63, Subpart DDDDD, NESHAP for Industrial Commercial, and Institutional Boilers and Process Heaters (NESHAP DDDDD or Boiler MACT). Compliance with these standards required changes to operating practices, including use of clean fuels for startup. Beginning in 2012, combustion efficiency improvements were made on Boilers 2 and 3 so that the Boiler MACT CO limits could be met. These improvements reduced CO emissions but did not increase NOx emissions. Boilers subject to NESHAP DDDDD were required to undergo a one-time energy assessment and are required to conduct tune-ups at a frequency specified by the rule.

1.4 DOCUMENT ORGANIZATION

The document is organized as follows:

- **Section 1 – Introduction:** provides the purpose of the document and what emission units are included in the analysis.
- **Section 2 – Four-Factor Analysis for Boilers:** provides the Four Factor analysis for the biomass boilers.
- **Section 3 – Four-Factor Analysis for Veneer Dryers:** provides the Four Factor analysis for the veneer dryers.
- **Section 4 – Four-Factor Analysis for Plywood Presses:** provides the Four Factor analysis for the plywood presses.

- **Section 5 – Summary of Findings:** presents a summary of the analysis.
- **Appendix A – Control Cost Analyses**
- **Appendix B – 2017 Actual Emissions**

2. FOUR FACTOR ANALYSIS FOR BOILERS

This section of the report presents the results of a Four Factor analysis for PM₁₀, SO₂, and NO_x emitted from the Medford Mill biomass boilers. The three boilers are biomass hybrid suspension grate units, are controlled by a dry electrostatic precipitator (ESP), and produce 50,000, 70,000, and 100,000 pounds of steam per hour at capacity, respectively. The Medford Mill typically operates two of the boilers at a time.

To evaluate the cost of compliance portion of the Four Factor analysis, the following steps were performed:

- identify available control technologies,
- eliminate technically infeasible options, and
- evaluate cost effectiveness of remaining controls.

The time necessary for compliance, energy and non-air environmental impacts, and remaining useful life were also evaluated.

2.1 AVAILABLE CONTROL TECHNOLOGIES

Available control options are those air pollution control technologies or techniques (including lower-emitting processes and practices) that have the potential for practical application to the emissions unit and pollutant under evaluation, with a focus on technologies that have been demonstrated to achieve the highest levels of control for the pollutant in question, regardless of the source type on which the demonstration has occurred. The scope of potentially applicable control options for industrial boilers was determined based on a review of the RBLC database³ and knowledge of typical controls used on boilers in the forest products industry. RBLC entries that are not representative of the type of emissions unit, or fuel being fired, were excluded from

³ RACT/BACT/LAER Clearinghouse (RBLC). <https://www.epa.gov/catc/ractbactlaer-clearinghouse-rblc-basic-information>

further consideration. Table 2-1 summarizes the potentially feasible control technologies for biomass boilers.

Table 2-1
Control Technology Summary

Pollutant	Controls on Industrial Boilers
PM ₁₀	Fabric filter ESP Wet scrubber
SO ₂	Wet scrubber Dry sorbent injection (DSI)
NO _x	Good combustion practices Selective non-catalytic reduction (SNCR) Selective Catalytic Reduction (SCR)

Technically feasible control technologies for biomass boilers were evaluated, considering current air pollution controls, fuels fired, and RBLC Database information. Note that fuel switching from biomass to natural gas was not evaluated because the purpose of this analysis is not to change the operation or design of the source or to evaluate alternative energy projects. The August 20, 2019 regional haze implementation guidance indicates that states may determine it is unreasonable to consider fuel use changes because they would be too fundamental to the operation and design of a source. EPA BACT guidance states that it is not reasonable to change the design of a source, such as by requiring conversion of a coal boiler to a gas turbine.⁴ It is not feasible to convert a biomass boiler at a wood products mill to a gas-fired boiler because biomass boilers at wood products mills fire the biomass residuals from the production processes.

⁴ <https://www.epa.gov/sites/production/files/2015-07/documents/igccbact.pdf>

2.1.1 Available PM₁₀ Control Technologies

The following control technologies were identified as potentially available for reducing emissions of PM₁₀ from industrial biomass boilers.

Electrostatic Precipitators

ESPs are widely used for the control of PM from a variety of combustion sources. An ESP is a particulate control device that removes particles from a gas stream by using electrical energy to charge particles either positively or negatively. The charged particles are then attracted to collector plates carrying the opposite charge. The collected particles are periodically removed from the collector plates. There are several different designs that can achieve very high overall control efficiencies. Control efficiencies typically average over 98% with control efficiencies almost as high for particle sizes of 1 micrometer or less. ESPs have been demonstrated in practice to have PM₁₀ removal efficiencies as high as those achieved by fabric filters. Two ESP designs are common: dry electrostatic precipitators and wet electrostatic precipitators. The systems are similar except that wet electrostatic precipitators use water to flush the captured particles from the collector plates.

Fabric Filters

Various types of fabric filters or bag houses have been successfully used for PM control on solid fuel-fired boilers. A fabric filter utilizes filtration to remove particles from the contaminated gas stream by passing the gas stream through the filter media, thereby depositing the suspended particles in the gas stream on fabric material. The ability of a fabric filter to collect sub-micrometer particles is due to the accumulation of dust cake onto the surface of the filter, and not the fabric itself. With the correct design and choice of fabric media, particulate matter control efficiencies of 99% or greater can be achieved even for very small particles (1 micrometer or less).

Wet Scrubbers

In wet scrubbing processes, liquid or solid particles are removed from a gas stream by transferring them to a liquid, most commonly water. The PM collection efficiency of a wet scrubber system is

directly related to the amount of energy expended in contacting the gas stream with the scrubber liquid. Wet scrubbers cannot typically achieve the levels of PM and PM₁₀ reduction obtained by fabric filters and ESPs without being operated at extremely high energy input levels. In addition, wet scrubber systems often require higher levels of maintenance and generate a wastewater stream that must be treated.

2.1.2 Available SO₂ Control Technologies

Biomass boilers generally emit low levels of SO₂ because of the inherent low level of sulfur in biomass fuel. However, the following add-on control technologies were identified as potentially feasible for reducing emissions of SO₂ from industrial biomass boilers.

Wet Scrubber

In wet scrubbing processes for gaseous contaminant control, a liquid is used to remove pollutants from an exhaust stream. The removal of pollutants in the gaseous stream is done by absorption. Wet scrubbers used for this type of pollutant control are often referred to as absorbers. Wet scrubbing involves a mass transfer operation in which one or more soluble components of an acid gas are dissolved in a liquid that has low volatility under process conditions. For SO₂ control, the absorption process is chemical-based and uses an alkali solution (i.e., sodium hydroxide, sodium carbonate, sodium bicarbonate, calcium hydroxide, etc.) as a sorbent or reagent in combination with water. Removal efficiencies are affected by the chemistry of the absorbing solution as it reacts with the pollutant. Wet scrubbers may take the form of a variety of different configurations including plate or tray columns, spray chambers, and venturi scrubbers.

Dry Sorbent Injection (DSI)

DSI accomplishes removal of acid gases by injecting a dry reagent (i.e., lime or trona) into the flue gas stream and prior to PM air pollution control equipment. A flue gas reaction takes place between the reagent and the acid gases, producing neutral salts that must be removed by the PM air pollution control equipment located downstream. The process is totally “dry,” meaning it produces a dry disposal product and introduces the reagent as a dry powder. The benefits of this

type of system include the elimination of liquid handling equipment requiring routine maintenance such as pumps, agitators, and atomizers. The drawbacks to using this type of system are the costs associated with the installation of a dry PM control device to collect the dry by-product, as well as ongoing operating costs to procure the sorbent material and dispose of additional dry waste. Dry sorbents can also prove challenging to maintain a very low moisture content and keep flowing. DSI systems are typically used to control SO₂, hydrochloric acid and other acid gases on coal-fired boilers.

2.1.3 Available NO_x Control Technologies

The following add-on control technologies were identified as potentially feasible for reducing emissions of NO_x from industrial boilers.

Good Operating Practices

Good operating practices were identified in the U.S. EPA RBLC database as a control technique for industrial boilers. Examples of good operating practices include but are not limited to: following manufacturer's written instructions, operating with sufficient excess air, optimum combustion temperatures, residence time, and maintaining a good mix of combustion air and fuel.

Water/Steam Injection

The addition of an inert diluent, such as water or steam, into the high temperature region of the boiler flame controls thermal NO_x generation by quenching peak flame temperatures, thus lowering overall NO_x levels. While atomized water or steam injection can reduce NO_x formation, flame instability, condensation problems and efficiency losses result when the water-to-fuel ratio becomes too high.

Low NO_x Burners (LNB)

The use of LNB is a front-end control technology for limiting NO_x emissions. An LNB is designed to control fuel and air mixing by staging the air or fuel in multiple zones and thus limit peak flame temperatures in the burners. NO_x reduction is accomplished in an LNB by using techniques such

as recycling internal gas, staging the combustion air, or injecting natural gas. These techniques would create burner temperatures that are below the peak NO_x formation temperature range, thus limiting NO_x formation, but potentially impacting CO emissions. LNB burner conversion capability may also be complicated by boiler age, configuration, and fire-box dimensions.

Flue Gas Recirculation (FGR)

FGR systems recirculate a portion of relatively cool exhaust gases back into the combustion zone to lower the peak flame temperature, thereby reducing NO_x emissions. The flame temperature is lowered as a result of the cooler recirculated air, diluting the oxygen content of the combustion air and causing the heat to be diluted in a greater mass of flue gas. FGR can be designed using an induced or external design. External FGR utilizes an external fan to recirculate the flue gases back into the combustion zone to lower peak flame temperatures. Induced FGR uses a combustion air fan to recirculate a portion of the flue gases back into the combustion zone where the flue gases and combustion air are premixed to lower the flame temperature in the burner.

Selective Non-Catalytic Reduction (SNCR)

SNCR is a control technology for NO_x emissions that uses a reduction-oxidation reaction to convert NO_x into N₂, H₂O, and carbon dioxide (CO₂). SNCR involves injecting ammonia or urea into a combustion chamber or the flue gas stream, which must be between approximately 1,600 and 2,000°F for the chemical reaction to occur. At low loads, temperatures may be less than the optimum required for achieving NO_x reductions. For example, a unit that experiences load swings according to production demands will have a variable temperature profile. To address this concern for a boiler, multiple levels of reagent injectors can be installed. Due to the energy penalty associated with the evaporation of the reagent within the furnace, additional fuel must be combusted, resulting in increased generation of fly ash.

Wood products mill boilers are operated to track steam loads required for facility processes and are not operated under base load conditions as are utility boilers. Furnace temperature tracks steam demand. If optimal furnace temperatures cannot be consistently maintained, the ammonia or urea injection rate needed to reduce NO_x emissions will result in excess reagent being present. This

ammonia will combine with chlorides and sulfur in the combustion gas and result in increased corrosion on downstream metal and heat surfaces. In addition, chlorides in the gas stream will combine with excess ammonia to create condensable PM_{2.5} particles in the flue gas, thereby increasing PM_{2.5} emissions. Ammonia emissions can also result in secondary formation of ammonia nitrates and sulfates, which are visibility impairing pollutants. Unreacted ammonia can also become part of the exhaust stream.

Selective Catalytic Reduction (SCR)

Although SCR was not identified in the RLBC search as a technology typically employed on biomass-fired industrial boilers, it has been applied to coal-fired utility boilers. SCR is a NO_x control technology that uses a catalyst to react injected anhydrous ammonia, aqueous ammonia or urea to chemically convert NO_x into N₂ and water (H₂O). SCR employs a metal-based catalyst, such as vanadium or titanium, to increase the rate of the NO_x reduction reaction⁵. The flue gases flow into a reactor module containing the catalyst where the reagent selectively reacts with the NO_x. The reduction reactions used by SCR are effective only within a given temperature range where ammonia or urea is injected into the exhaust gases in a temperature range of 480°F – 800°F⁶. The presence of alkali metals such as sodium and potassium, which are commonly found in wood, but not fossil fuels, will poison catalysts and the effects are irreversible. Other naturally occurring catalyst poisons found in wood are phosphorous and arsenic. Therefore, it is not feasible to place an SCR upstream of a particulate control device on a biomass boiler.

Under optimum temperatures, amount of reducing agent and injection grid design, SCR can achieve 90 percent reduction of NO_x. However, ammonia slip can also occur, which refers to the emissions of unreacted ammonia due to the incomplete reaction of the reagent and NO_x. As discussed above, excess ammonia can result in formation of compounds that cause corrosion and

⁵ Chapter 2 Selective Catalytic Reduction, OAQPS 7th Edition (June 2019). https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf (Section 2.2.1).

⁶Air Pollution Control Technology Fact Sheet. EPA-452/F-03-032. <https://www3.epa.gov/tncate1/dir1/fscr.pdf>. (pg. 1).

impair visibility. Ammonia slip can also occur, which refers to the emissions of unreacted ammonia due to the incomplete reaction of the reagent and NO_X.

2.2 ELIMINATION OF TECHNICALLY INFEASIBLE OPTIONS

An available control technique may be eliminated from further consideration if it is not technically feasible for the specific source under review. A demonstration of technical infeasibility must be documented and show, based on physical, chemical, or engineering principles, that technical reasons would preclude the successful use of the control option on the emissions unit under review. U.S. EPA generally considers a technology to be technically feasible if it has been demonstrated and operated successfully on the same type of emissions unit under review or is available and applicable to the emissions unit type under review. If a technology has been operated on the same type of emissions unit, it is presumed to be technically feasible. However, an available technology cannot be eliminated as infeasible simply because it has not been used on the same type of unit that is under review. If the technology has not been operated successfully on the type of unit under review, its lack of “availability” and “applicability” to the particular unit type under review must be documented in order for the technology to be eliminated as technically infeasible.

PM₁₀ Emissions

Due to the typically lower PM₁₀ removal efficiencies than dry ESPs, and the generation of wastewater, this analysis does not consider the use of wet controls for PM₁₀ emissions control. Fabric filters are rarely implemented on wood-fired boilers due to risk of fire (any retrofit implementation would require a long stretch of ductwork between the economizer and the control device to reduce the risk of fire). ESPs are almost as efficient as the best fabric filters without the fire risk.⁷ ESPs can withstand higher temperatures, have a smaller footprint, use less energy, and have lower maintenance requirements and better separation efficiencies than fabric filters. Therefore, use of a fabric filter for PM₁₀ control was not considered feasible and was not evaluated.

⁷ https://www.biomasscenter.org/images/stories/FSE_PM_Emissions.pdf

The Medford Mill biomass boilers are already very well controlled and are subject to a stringent PM emission limit based on a LAER analysis, as well as Boiler MACT emission limits and work practices. Because the August 20, 2019 EPA Regional Haze Guidance⁸ mentions that states can exclude sources that have been through LAER review from further analysis, we have not evaluated further PM₁₀ controls on the biomass boilers.

SO₂ Emissions

The Medford Mill biomass boiler emits very little SO₂ because biomass is an inherently low-sulfur fuel. Biomass boilers typically do not require add-on SO₂ controls unless they are burning fuels or process gases that contain significant amounts of sulfur. A wet scrubber is not feasible because the mill does not have a wastewater treatment plant. It may be technically feasible to inject trona prior to the ESP to achieve some SO₂ control.

NO_x Emissions

NO_x emissions from biomass boilers originate primarily from oxidation of fuel bound nitrogen⁹. The Medford Boilers are in the biomass hybrid suspension grate subcategory under the Boiler MACT rule. Biomass is fed to the boilers via air-swept spouts, begins to combust in suspension, and then completes combustion on a grate. Low-NO_x burners and water injection are not applicable to this design. The air system is optimized during required Boiler MACT tune-ups and FGR is not likely to provide a significant reduction in NO_x.

Add-on NO_x controls such as SNCR and SCR require a specific temperature window to be effective. These controls were developed for and have predominantly been applied to fossil fuel fired boilers. There are challenges associated with applying SNCR to an industrial biomass boiler due to variability in boiler load. Good mixing of the reagent and NO_x in the flue gas at the optimum temperature window is the key to achieving a NO_x reduction for SCR and SNCR. In

⁸ See page 23 of the guidance at https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-regional_haze_guidance_final_guidance.pdf

⁹ NCASI Technical Bulletin 1020, Compilation of Criteria Air Pollutant Emissions Data for Sources at Pulp and Paper Mills Including Boilers – An Update to Technical Bulletin No. 884, December 2013.

biomass boilers, this temperature window is a function of the variations in fuel quality and the load on the boiler. The temperature profile in a wood-fired industrial boiler is not as constant as that of a fossil fuel-fired utility boiler. Biomass boilers at forest products mills are often subject to highly variable swings in steaming rate, fuel flow, fuel mix, and bark moisture, depending on mill steam demand, availability of bark, amount of other fuels fired, and weather conditions.

In biomass boilers, the firebox temperature varies with boiler load and fuel quality. Bark quality and moisture are not consistent. Wide variations in firebox and flue gas temperatures are associated with varying steam load and fuel mix. This causes the narrow temperature window for SNCR to vary spatially in the boiler. The variability of the SNCR temperature window is a critical issue, because of the consequences of ammonia injection outside this window. Below the temperature window, ammonia slip will occur due to incomplete reactions of the injected chemicals with the NO_x. Above the temperature window, the reducing chemicals could be combusted to form additional NO_x. Multiple injection levels must typically be installed if SNCR is applied on a biomass boiler.

Additional water, power, and boiler fuel are required to operate the SNCR system because the SNCR process reduces the thermal efficiency of the boiler. The reduction reaction uses thermal energy from the boiler, which decreases the energy available for power or heat generation. As a result, additional fuel is required for the boiler to maintain the same steam output (resulting in additional emissions of other pollutants, including greenhouse gases). Despite operational challenges, SNCR cost effectiveness was evaluated at a control efficiency of 40% and using a retrofit factor of 1.5 to account for difficulty of a potential retrofit and the need to install multiple injection points.

The feasibility of SCR application to biomass boilers is also uncertain. SCR uses a catalyst to reduce NO_x to nitrogen, water, and oxygen. SCR technology employs aqueous or anhydrous ammonia as a reducing agent that is injected into the gas stream near the economizer and upstream of the catalyst bed. The catalyst lowers the activation energy of the NO_x decomposition reaction. An ammonium salt intermediate is formed at the catalyst surface and subsequently decomposes to

elemental nitrogen and water. This technology has been demonstrated mostly on large coal- and natural gas-fired combustion units in the utility industry.

In practice, SCR systems operate at NO_x control efficiencies in the range of 70 to 90% for fossil fuel utility boilers. Optimum temperatures for the SCR process range from 480 to 800°F. Due to catalyst plugging and poisoning problems associated with locating the catalyst prior to the particulate control device, an SCR system would have to be installed after an existing particulate control device, and would likely require installation of a gas-fired flue gas re-heater to achieve the optimum reaction temperature (the flue gas temperature for biomass boilers is typically less than 480°F). This would incur associated fuel costs and pollution increases, running counter to the administration's goal to reduce greenhouse gases, assuming there is adequate space to install the size re-heater needed to raise the temperature of the exhaust gas stream to the optimum temperature of 600 °F. Despite these challenges, for purposes of this analysis, we evaluated cost effectiveness of an SCR achieving 90% control, but we incorporated a retrofit factor of 1.5 to account for the difficulty of applying SCR to a biomass boiler and the likely need to add ductwork and to replace the fan to overcome additional pressure drop through the system.

2.3 COST AND IMPACTS OF TECHNICALLY FEASIBLE CONTROL TECHNOLOGIES

Cost analyses were developed where add-on controls could be technically feasible. Budgetary estimates of capital and operating costs were determined and used to estimate the annualized costs for each control technology considering existing equipment design and exhaust characteristics. A capital cost for each control measure evaluated was based on company-specific data, previously developed industry project costs, or EPA cost spreadsheets. The cost effectiveness for each technically feasible control technology was calculated using the annualized capital and operating costs and the amount of pollutant expected to be removed based on a typical expected control efficiency and the procedures presented in the latest version of the U.S. EPA OAQPS Control Cost Manual. An interest rate of 4.75% and the typical values for equipment life shown in the Cost Manual examples were used to calculate the capital recovery factor. A 4.75% interest rate represents the prime rate just prior to the pandemic (at the time of DEQ's request for the Four

Factor Analysis) and is representative because the prime rate has varied over the past two years from the current low of 3.25% to a high of 5.5% in December 2018.

Control technologies that were evaluated and for which a cost analysis was performed are summarized in Table 2-2.

Table 2-2
Control Technologies Evaluated for Boilers

Emissions Unit	Fuels Fired	Existing Control Technology			Additional Control Technology Costed		
		PM₁₀	NO_x	SO₂	PM₁₀	NO_x	SO₂
Biomass Boilers (3) (EU1)	Biomass	ESP	Good combustion	Low-sulfur fuel	None (ESP is LAER)	SNCR SCR	DSI

Capital, operating, and total annual cost estimates for each feasible pollution control technique are presented in Appendix A. We note that these are screening level cost estimates and are not based on detailed engineering studies of the Medford Mill boilers. Where initial cost estimates demonstrated that a particular control technology was not cost effective, we did not attempt to refine the analysis further.

Although DEQ has not indicated what additional controls they would consider cost effective, the Medford Mill has referenced similar analyses performed by U.S. EPA and others to get a general idea of the level above which additional controls on industrial boilers are not cost effective. As part of the 2016 CSAPR update rule¹⁰, U.S. EPA performed an analysis to characterize whether there were non-EGU source groups with a substantial amount of available cost-effective NO_x reductions achievable by the 2017 ozone season. They evaluated control costs for non-EGU point

¹⁰ 81 Fed. Reg. 74504

sources with NO_x emissions greater than 25 tpy in 2017.¹¹ U.S. EPA did not further examine control options above \$3,400 per ton. This is consistent with the range U.S. EPA analyzed for EGUs in the proposed and final CSAPR rules and is also consistent with what the U.S. EPA has identified in previous transport rules as cost-effective, including the NO_x SIP call. Note that industrial boilers were among the source categories that the very conservative U.S. EPA cost analysis determined were above \$3,400/ton. In addition, the Western Regional Air Partnership (WRAP) Annex to the Grand Canyon Visibility Transport Report (June 1999) indicated that control costs greater than \$3,000/ton were high.¹² The costs presented in this report were developed using conservative assumptions and are above these thresholds.

2.3.1 Site Specific Factors Limiting Implementation

Currently known, site-specific factors that would limit the feasibility and increase the cost of installing additional controls include space constraints. Note that a detailed engineering study for each of the controls evaluated in this report would be necessary before any additional controls were determined to be feasible or cost effective.

2.3.2 SO₂ Economic Impacts

Trona Injection for Boiler SO₂ Control

The capital cost for a system to inject milled trona prior to the ESP on the boilers was estimated using an April 2017 Sargent and Lundy report prepared under an U.S. EPA contract.¹³ Industry standard labor, chemical, and utility costs were used to estimate the annual cost of operating the system. Table 2-3 summarizes the capital cost, annual cost, and cost effectiveness of implementing this control technology for the boilers. The Sargent and Lundy report indicates that 50% SO₂

¹¹ Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS, Docket ID EPA-HQ-OAR-2015-0500, Assessment of Non-EGU NO_x Emission Controls, Cost of Controls, and Time for Compliance, U.S. EPA, November 2015.

¹² https://www.wrapair.org//forums/mtf/documents/group_reports/TechSupp/SO2Tech.htm

¹³ Sargent & Lundy LLC. 2017. *Dry Sorbent Injection for SO₂/HCl Control Cost Development Methodology*. Project 13527-001, Eastern Research Group, Inc. Chicago, IL.

control can be achieved without an increase in PM emissions when injecting trona prior to an ESP. The cost of installing DSI prior to the ESP is not considered cost effective because the estimated capital cost is more than \$4 million and the cost effectiveness value is in excess of \$60,000/ton of pollutant removed, even when evaluated at the allowable SO₂ emission rate of 39 tpy. The cost per ton would be even higher if evaluated based on the actual SO₂ emission rate from biomass. Detailed cost calculations are presented in Appendix A, Table A-1.

Table 2-3
Trona Injection System Cost Summary

Emissions Unit Description	Capital Cost (\$)	Annual Cost (\$/yr)	Cost Effectiveness of Controls (\$/Ton SO ₂)
Biomass Boilers	\$4,361,740	\$1,192,287	\$61,143

2.3.3 NO_x Economic Impacts

This section describes the economic impacts associated with each NO_x add-on control option evaluated for the boilers. Note that cost effectiveness was evaluated based on the PSEL, and the cost per ton would be even higher if evaluated based on actual emissions.

SNCR for Boiler NO_x Control

The cost of installing and operating SNCR on the boilers was estimated using U.S. EPA “Air Pollution Control Cost Estimation Spreadsheet for Selective Non-Catalytic Reduction (SNCR)” (June 2019) that reflects calculation methodologies presented in the U.S. EPA Air Pollution Control Cost Manual, Section 4, Chapter 1. The spreadsheet, using algorithms presented in the control cost manual, calculates estimated capital and annualized costs of installing and operating an SNCR based on site-specific data entered, such as boiler design and operating data. Note that the cost algorithms were developed using project costs for large coal-fired utility boilers and the spreadsheets are labeled as if costs are being estimated for a coal-fired boiler. As a result, they likely underestimate costs for smaller industrial boilers as costs for large utility boilers where this technology is routinely installed may not scale to smaller, variable load industrial boilers. The U.S. EPA cost manual allows a retrofit factor of greater than one where justification is provided.

A retrofit factor of 1.5 was applied to account for the need to add multiple levels of reagent injectors and to perform additional tuning of the system across variable loads.

SNCR control efficiencies vary widely, but urea-based systems typically achieve reductions from 37 to 60 percent on industrial boilers, according to the OAQPS Control Cost Manual. However, operating constraints on temperature, load, reaction time, and mixing often lead to less effective results when using SNCR in practice. Our analyses assume that SNCR would achieve 40% NO_x control because the biomass boilers are subject to regular load swings. This control efficiency is supported by the range provided in the OAQPS Cost Manual and information publicly available from vendors.¹⁴ A formal engineering analysis would be required to ultimately determine if SNCR would be effective on the boilers. This type of analysis would include obtaining temperature and flow data, developing a model of each boiler using computational fluid dynamics, determining residence time and degree of mixing, determining placement of injectors, and testing.

Table 2-4 summarizes the estimated capital cost, annual cost, and cost effectiveness of implementing SNCR control technology. The cost analysis is based on the boilers' capacity and their 210 tpy portion of the NO_x PSEL, although actual emissions in 2017 were only 105 tpy. The installed cost is likely underestimated because the cost is based on combined emissions from the three units. In reality, each boiler would need its own system. However, the boilers' portion of the PSEL and all emissions data are based on the three units combined because they vent to a common ESP and stack. Installing SNCR is not considered cost effective because the capital cost is over \$5 million and the cost effectiveness is in excess of \$3,400/ton of pollutant removed, the cost effectiveness threshold for non-EGUs used by EPA for similar studies. Detailed cost calculations are presented in Appendix A, Table A-2.

¹⁴ See for example, <https://www.eescorp.com/solutions/sncr/>, <https://www.cecoenviro.com/selective-non-catalytic-reduction-sncr-cca-combustion-systems>, <https://www.ftek.com/en-US/products/productssubapc/urea-sncr>

Table 2-4
SNCR Cost Summary

Emissions Unit Description	Capital Cost (\$)	Annual Cost (\$/yr)	Cost Effectiveness of Controls (\$/Ton NO _x)
Biomass Boilers	\$5,442,414	\$856,480	\$10,196

SCR for Boiler NO_x Control

The cost of installing and operating SCR on the boilers was estimated using the U.S. EPA “Air Pollution Control Cost Estimation Spreadsheet for Selective Catalytic Reduction (SCR)” (June 2019) that reflects calculation methodologies presented in the U.S. EPA Air Pollution Control Cost Manual, Section 4, Chapter 2. The spreadsheet, using algorithms presented in the control cost manual, calculates estimated capital and annualized costs of installing and operating an SCR based on site specific data entered, such as boiler design and operating data. Note that the cost algorithms were developed based on project costs for large coal-fired utility boilers and the spreadsheets are labeled as if costs are being estimated for a coal-fired boiler. As a result, they likely underestimate costs for smaller industrial boilers as costs for large utility boilers, where this technology is routinely installed, may not scale to smaller, variable load industrial boilers. The U.S. EPA cost manual allows a retrofit factor of greater than one where justification is provided. A retrofit factor of 1.5 was applied because the EPA cost equations were developed based on utility boiler applications and to account for space constraints, additional ductwork, the need for stack reheat, and the likelihood of needing a new induced draft fan to account for increased pressure drop.

Table 2-5 summarizes the capital cost, annual cost, and cost effectiveness of implementing SCR control technology on the combined emissions of the three boilers. The cost analysis is based on the boilers’ capacity and their NO_x PSEL of 210 tpy, although actual emissions in 2017 were only 105 tpy. Installing an SCR is not considered cost effective because the capital cost is estimated at more than \$27 million and the cost effectiveness values are well in excess of \$3,400/ton of pollutant removed, the cost effectiveness threshold for non-EGUs used by EPA for similar studies. Detailed cost calculations are presented in Appendix A, Table A-3.

Table 2-5
SCR Cost Summary

Emissions Unit Description	Capital Cost (\$)	Annual Cost (\$/yr)	Cost Effectiveness of Controls (\$/Ton NO _x)
Biomass Boilers	\$27,100,909	\$2,527,428	\$13,373

2.3.4 Energy and Non-Air Related Impacts

The environmental and energy impacts associated with SNCR include storage of additional chemicals onsite (the reagent), ammonia slip, and generation of additional emissions due to additional fuel combustion to overcome the energy penalty associated with SNCR. The environmental and energy impacts associated with SCR include the additional fuel usage and emissions from a stack reheat system and the transport, storage, handling, and use of aqueous ammonia, a corrosive hazardous material. Ammonia poses a potential exposure health and safety risk. The spent catalyst from the SCR would be required to be periodically replaced and disposed of properly, creating residual waste that would need to be landfilled or otherwise disposed. SCR systems can have adverse air impacts due to ammonia slip, possible formation of a visible plume, oxidation of carbon monoxide (CO) to carbon dioxide (CO₂), and oxidation of SO₂ to sulfur trioxide with subsequent formation of sulfuric acid mist due to ambient or stack moisture. Impacts of any NO_x reduction strategy on CO emissions would need to be carefully evaluated.

2.4 TIME NECESSARY FOR COMPLIANCE

U.S. EPA allows three years plus an optional extra year for compliance with MACT standards that require facilities to install controls. The process to retrofit air pollution controls on existing facility equipment is complex. Although our analysis shows there are no additional controls that would be economically feasible, if controls are ultimately required to meet RHR requirements, facilities would need at least four years to implement them. The facility would need time to obtain corporate approval for capital funding. The affected units at the facility would have to undergo substantial

re-engineering (e.g., due to space constraints) to accommodate new controls. Design, procurement, installation, and shakedown of these capital intensive projects would easily consume three years. The facility would need to engage engineering consultants, equipment vendors, construction contractors, financial institutions, and other critical suppliers. The facility would also need to initiate and execute modifications to air permits, which are often time-consuming and have an indeterminate timeline and endpoint. Lead time would be needed to procure pollution control equipment even after it is designed and a contract is finalized, and installation of controls must be aligned with mill outage schedules that are difficult to move due to the interrelationships within corporate mill systems and the availability of contractors. The facility would need to continue to operate as much as possible while retrofitting to meet any new requirements.

Any work on the boilers themselves would need to be staggered so only one unit was out of service at a time. Staggering work on separate units at the same facility allows some level of continued operation; however, this staggering extends the overall compliance time. Extensive outages for retrofitting must be carefully planned. Only when all the critical prerequisites for the retrofit have been identified and secured, e.g., the engineering is complete and the control equipment is staged for immediate installation, can an owner afford to shut down equipment to install new controls. This takes planning and coordination both within the company, with the contractors, and with customers.

2.5 REMAINING USEFUL LIFE OF EXISTING AFFECTED SOURCES

The emissions units and controls included in this analysis have a remaining useful life of twenty years or more.

2.6 CONCLUSION

Based on the Four Factor analysis presented above, no additional controls were determined to be cost effective for the biomass boilers at the Medford Mill.

3. FOUR FACTOR ANALYSIS FOR VENEER DRYERS

This section of the report presents the results of a Four Factor analysis for PM₁₀, SO₂, and NO_x emitted from the veneer dryers at the Medford Mill.

3.1 FEASIBILITY, COST, AND IMPACTS OF ADDITIONAL CONTROLS

The scope of potentially applicable control options for plywood veneer dryers was determined based on a review of the RBLC database and knowledge of typical fuels fired and controls used in the wood products industry. The RBLC database provides only one entry for PM₁₀ (ID MT-0021), two entries for NO_x (IDs LA-0125 and LA-0259), and no entries for SO₂ emissions from plywood veneer dryers. Emissions of volatile organic compounds (VOC) associated with plywood veneer dryer hot zones are controlled with either regenerative thermal oxidizers (RTO) or regenerative catalytic oxidizers (RCO) to meet Plywood and Composite Wood Products (PCWP) NESHAP requirements for HAP emissions control. The Medford Mill uses two RTOs to control volatile HAP emissions from the veneer dryers. Originally, the units operated in RCO mode, but are currently operated in RTO mode at a higher temperature. Although some types of wood products plants utilize PM control devices between the dryers and the RCO/RTO, veneer dryers have much lower PM emissions rates and do not use intermediate PM controls because they are not needed to protect the catalyst of an RCO or the heat exchange media of an RTO. Emissions of PM₁₀ from the veneer dryers are controlled by the RTOs because the majority of the PM₁₀ is condensable. Based on 2017 emissions test data, RTO1 total PM emissions were determined to be 1.06 lb/hr (less than 5 tpy) and RTO2 total PM emissions were determined to be 1.77 lb/hr (less than 8 tpy).

There are no plywood veneer dryers that are equipped with traditional PM₁₀ controls and additional PM₁₀ emissions controls may not provide a meaningful reduction in emissions. However, for completeness, and because the veneer dryers' portion of the PM₁₀ PSEL is 60 tpy, a cost estimate to add one polishing wet ESP to control emissions from both RTOs is provided. (Note that due to the distance between the two RTOs it may not actually be feasible to control emissions from both RTOs in one device, which would increase the cost.) The capital cost is based on the low end of

the range presented in an EPA wet ESP fact sheet¹⁵ and is within the range of particleboard, oriented strand board, and medium density fiberboard dryer wet ESP capital cost data obtained by EPA as part of the PCWP MACT information collection request (ICR¹⁶). The operating costs are based on the EPA OAQPS Cost Manual algorithms for ESPs in Section 6, Chapter 3, dated September 1999. Even assuming that a wet ESP would achieve a 99 percent reduction of the PSEL of 60 tpy, installing a wet ESP for additional PM₁₀ control is not cost effective. Detailed cost calculations are presented in Appendix A, Table A-4. Other environmental and energy impacts from installation of a wet ESP include water use, wastewater disposal, and additional electricity use.

Table 3-1
Wet ESP Cost Summary

Emissions Unit Description	Capital Cost (\$)	Annual Cost (\$/yr)	Cost Effectiveness of Controls (\$/Ton PM₁₀)
Veneer Dryer RTOs	\$15,330,560	\$1,908,545	\$34,686

The Medford Mill veneer dryers are indirect steam heated and do not have burners. The RTOs each have actual and allowable NO_x emissions of less than 5 tpy (1.3 tpy for RTO1 and 2.0 tpy for RTO2). Therefore, they are already low-emitting and there is no additional control technology that would be cost effective.

Insignificant SO₂ emissions are expected from the veneer dryers RTOs (0.1 tpy or less). Therefore, there are no control technologies to evaluate for SO₂ emissions from the veneer dryers RTOs.

¹⁵ <https://www3.epa.gov/ttn/catc/dir1/fwespwp1.pdf>

¹⁶ The ICR database is available in the rulemaking docket at <https://www.regulations.gov/docket?D=EPA-HQ-OAR-2016-0243>

3.2 TIME NECESSARY FOR COMPLIANCE

U.S. EPA allows three years plus an optional extra year for compliance with MACT standards that require facilities to install controls. Although our analysis shows there are no additional controls that would be economically feasible, if controls are ultimately required to meet RHR requirements, facilities would need at least four years to implement them for the reasons discussed in Section 2.

3.3 REMAINING USEFUL LIFE OF EXISTING AFFECTED SOURCES

The emissions units included in this analysis have a remaining useful life of twenty years or more.

3.4 CONCLUSION

Based on the Four Factor analysis presented above, no additional controls were determined to be economically feasible for the Medford Mill veneer dryers.

4. FOUR FACTOR ANALYSIS FOR PLYWOOD PRESSES

Plywood presses emit fugitive VOC and PM₁₀ as sheets of wood veneer are pressed together using hot platens; they do not emit NO_x or SO₂. Plywood assembly operations are located within two buildings. Because plywood presses are co-located with other process units, it is likely that the limited plywood press emissions data that have been collected by the National Council for Air and Stream Improvement (NCASI)¹⁷ also includes fugitive emissions from other different types of process units in the same building. Nevertheless, estimated plywood press PM₁₀ emissions are less than 25 tpy.

Plywood manufacturing facilities are subject to the NESHAP for Plywood and Composite Wood Products (PCWP) at 40 CFR 63, Subpart DDDD. Although veneer dryers are subject to standards, EPA determined that emissions from plywood presses were not amenable to capture and control and did not set any standards for these sources. EPA distinguished emissions control requirements for plywood presses from certain other reconstituted wood products presses (e.g., particleboard, OSB, and medium density fiberboard) “because of different emissions characteristics and the fact that plywood presses are often manually loaded and unloaded (unlike reconstituted wood product presses that have automated loaders and unloaders).”¹⁸ By virtue of issuing emission control standards only for certain reconstituted wood products presses, EPA essentially determined that emissions capture and control is practicable for other types of presses, but not plywood presses. In the September 2019 PCWP NESHAP risk and technology review proposal, EPA determined risk from the PCWP source category is acceptable and did not propose to add standards for plywood presses.

¹⁷ NCASI is an association organized to serve the forest products industry as a center of excellence providing unbiased, scientific research and technical information necessary to achieve the industry’s environmental and sustainability goals.

¹⁸ EPA, “National Emission Standards for Hazardous Air Pollutants for Plywood and Composite Wood Products Manufacturing—Background Information for Final Standards.” February 2004.

The RBLC includes no entries for plywood presses with add-on emissions controls. The EPA database of emission sources that was developed for the risk and technology review of the PCWP NESHAP indicates that no plywood presses at HAP major sources are enclosed or controlled. We are aware of one minor source (Freres Lumber) that installed a partial enclosure and a biofilter to control formaldehyde and methanol emissions to reduce HAP emissions below major source levels and avoid coverage under the PCWP NESHAP, but they are the only facility that has any emissions controls on a plywood press, and the biofilter is not in place to control PM₁₀ emissions.

Plywood presses are fugitive sources, although some emissions pass through the building roof vents above the presses. Existing vents in the vicinity of these process units are not intended to quantitatively capture and exhaust gaseous emissions specifically from the plywood presses; rather, they are strategically placed to evacuate building air. When the process and building ventilation layouts were designed, the possibility of emissions capture or testing was not contemplated and is impracticable for these existing sources.

Plywood presses are not enclosed because they are constantly accessed by employees. Plywood manufacturing facilities typically have one layup line that feeds multiple presses. On the layup line, layers of dried veneer are laid down in alternating directions with resin applied between each layer. At the end of the line, the layered mat is trimmed, stacked, and moved to the press infeed area for each press. This configuration requires more operating space and manual input than other wood products manufacturing processes. Plywood presses are batch processes and loading the press is manually assisted (the press charger is manually loaded). Operators must be able to observe press operation to check that the press is properly loaded. Each batch of pressed plywood is removed from the area using a forklift. Accordingly, forklifts are entering the press unloader continuously. Adding an enclosure to capture emissions is not feasible because it would disrupt operation of the press (both infeed and outfeed), inhibit maintenance activities, and create unsafe working conditions for employees (isolation, reduced egress, heat, and emissions).

There are no technically feasible controls to reduce plywood press PM₁₀ emissions. Therefore, the cost of controls has not been evaluated.

5. SUMMARY OF FINDINGS

The largest emission sources at the Medford Mill are already well-controlled and are subject to various stringent individual source emission limits. However, in response to a request from DEQ, the Medford Mill evaluated whether additional emissions controls for SO₂, NO_x, and PM₁₀ are feasible for its significant emissions units.

As part of the analysis, the following information was reviewed: site-specific emissions and controls information, industry- and site-specific cost data, previous similar control evaluations, the EPA RBLC database, and the EPA Control Cost Manual. BCWP and ALL4 used the best information available in the time allotted to perform the analyses. Site-specific engineering analyses were not performed.

Our review of the best available information indicates that additional emissions controls for SO₂, NO_x, and PM₁₀ are either not technically feasible or they are not economically feasible when they may be technically feasible. Any determination that additional controls are economically feasible would need to be further justified based on a detailed engineering evaluation that fully considers site-specific factors. In addition, the following points are noted:

- Medford Mill significant emissions units amenable to cost effective emissions capture and control are already well controlled.
- The biomass boilers included in the analysis are subject to MACT emission limits and work practice standards that directly limit emissions of PM₁₀. The boiler tune-up requirement serves to minimize NO_x emissions by promoting good combustion techniques.
- EPA will continue the required process to evaluate particulate and acid gas control technology improvements for the industrial boiler source category with its upcoming periodic technology reviews for NESHAP Subpart DDDDD sources.
- EPA determined in its CSAPR rulemaking that additional NO_x controls on non-EGU boilers are not cost effective.

**APPENDIX A -
CONTROL COST ANALYSES**

- The plywood manufacturing operations are subject to MACT requirements that are currently undergoing review by EPA. Veneer dryer emissions are controlled using RTOs and plywood press emissions are not feasible to capture and control.

Table A-1
Medford Biomass Boilers
Capital and Annual Costs Associated with Milled Trona DSI System with an ESP

Variable	Designation	Units	Value	Calculation
Unit Size	A	MW	30	77+108+154 MMBtu/hr, assumes 30% efficiency to convert to equivalent MW output
Retrofit Factor	B	-	1.5	Based on space constraints
Gross Heat Rate	C	Btu/kWh	8,619	Assumes 30% efficiency
SO ₂ Rate (uncontrolled)	D	lb/MMBtu	0.025	AP42 Table 1.6-2
Type of Coal	E	-	NA	
Particulate Capture	F	-	ESP	
Sorbent	G	-	Milled Trona	
Removal Target	H	%	50	Per the Sargent and Lundy document, 50% reduction can be achieved without an increase in PM emissions.
Heat Input	J	Btu/hr	3.39E+08	77 MMBtu/hr + 108 MMBtu/hr + 154 MMBtu/hr
NSR	K	-	1.43	Milled Trona w/ ESP = if (H<40, 0.0270*H, 0.353e^(0.0280*H))
Sorbent Feed Rate	M	ton/hr	0.01	Trona = (1.2011*10^-06)*K*A*C*D
Estimated HCl Removal	V	%	92.89	Milled or Unmilled Trona w/ ESP = 60.86*H^0.1081
Sorbent Waste Rate	N	ton/hr	0.01	Trona = (0.7387+0.00185*H/K)*M
Fly Ash Waste Rate	P	ton/hr	1.12	Ash in Bark = 0.05; Boiler Ash Removal = 0.2; HHV = 4600 (A*C)*Ash*(1-Boiler Ash Removal)/(2*HHV)
Aux Power	Q	%	0.01	Milled Trona M*20/A
Sorbent Cost	R	\$/ton	170	
Waste Disposal Cost	S	\$/ton	50	
Aux Power Cost	T	\$/kWh	0.07	2019 mill cost
Operating Labor Rate	U	\$/hr	33	Typical operator labor cost including all benefits

SO ₂ Control Efficiency:	50%
PSEL, tpy	39.0 represents all 3 boilers - actual emissions are only 15 tpy
Controlled SO ₂ Emissions:	19.5

Capital Costs					
Direct Costs					
BM (Base Module)	-	\$	\$	3,461,698	Milled Trona if(M>25, 820000*B*M, 8300000*B*(M^0.284))
Indirect Costs					
Engineering & Construction					
Management	A1	\$	\$	346,170	10% BM
Labor adjustment	A2	\$	\$	173,085	5% BM
Contractor profit and fees	A3	\$	\$	173,085	5% BM
Capital, engineering and construction cost subtotal	CECC	\$	\$	4,154,038	BM+A1+A2+A3
Owner costs including all "home office" costs	B1	\$	\$	207,702	5% CEC
Total project cost w/out AFUDC	TPC	\$	\$	4,361,740	B1+CEC
AFUDC (0 for <1 year engineering and construction cycle)	B2	\$		0	0% of (CECC+B1)
Total Capital Investment	TCI	\$	\$	4,361,740	CECC+B1+B2

Annualized Costs				
Fixed O&M Cost				
Additional operating labor costs	FOMO	\$	\$	137,280 (2 additional operator)*2080*U
Additional maintenance material and labor costs	FOMM	\$	\$	23,078 BM*0.01/B
Additional administrative labor costs	FOMA	\$	\$	4,395 0.03*(FOMO+0.4*FOMM)
Total Fixed O&M Costs	FOM	\$	\$	164,753 FOMO+FOMM+FOMA
Variable O&M Cost				
Cost for Sorbent	VOMR	\$	\$	16,429.7 M*R
Cost for waste disposal that includes both sorbent & fly ash waste not removed prior to sorbent injection	VOMW	\$	\$	492,664.4 (N+P)*S
Additional auxiliary power required	VOMP	\$	\$	1,353.03 Q*T*10*ton SO ₂
Total Variable O&M Cost	VOM	\$	\$	510,447.1 VOMR+VOMW+VOMP
Indirect Annual Costs				
General and Administrative	2%	of TCI	\$	87,235
Property Tax	1%	of TCI	\$	43,617
Insurance	1%	of TCI	\$	43,617
Capital Recovery	7.86%	x TCI	\$	342,617
Total Indirect Annual Costs			\$	517,086
Life of the Control:	20	years	4.75%	interest
Total Annual Costs		\$	1,192,287	
Total Annual Costs/SO₂ Emissions		\$	61,143	

^(a)Cost information based on the April 2017 "Dry Sorbent Injection for SO₂/HCl Control Cost Development Methodology" study by Sargent & Lundy for a milled Trona system.

Table A-2. SNCR Cost for Medford Biomass Boilers
Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

Industrial

Is the SNCR for a new boiler or retrofit of an existing boiler?

Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.

1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?

339 MMBtu/hour

What is the higher heating value (HHV) of the fuel?

4,600 Btu/lb

What is the estimated actual annual fuel consumption?

297,504,000 lbs/Year

Is the boiler a fluid-bed boiler?

No

Enter the net plant heat input rate (NPHR)

10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned:

Bituminous

Enter the sulfur content (%S) = 0.07 percent by weight

or

Select the appropriate SO₂ emission rate:

Not Applicable

Ash content (%Ash): 5 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost (\$/MMBtu)
Bituminous	0	1.84	9.23	11,841
Sub-Bituminous	0	0.41	5.84	8,826
Lignite	0	0.82	13.6	6,626

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})

365 days

Inlet NO_x Emissions (NO_{x,in}) to SNCR

lb/MMBtu (based on 0.26 lb
0.17 NO_x/MMBtu steam and est.
65% efficiency)

Outlet NO_x Emissions (NO_{x,out}) from SNCR

0.102 lb/MMBtu

Estimated Normalized Stoichiometric Ratio (NSR)

2.75

Plant Elevation

1382 Feet above sea level

Concentration of reagent as stored (C_{stored})

50 Percent

Density of reagent as stored (ρ_{stored})

71 lb/ft³

Concentration of reagent injected (C_{inj})

10 percent

Number of days reagent is stored ($t_{storage}$)

14 days

Estimated equipment life

20 Years

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

Select the reagent used

Urea ▾

Densities of typical SNCR reagents:

50% urea solution	71 lbs/ft ³
29.4% aqueous NH ₃	56 lbs/ft ³

Enter the cost data for the proposed SNCR:

Desired dollar-year

2019

CEPCI for 2019

603.1 Enter the CEPCI value for 2019

541.7 2016 CEPCI

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i)

4.75 Percent

Fuel (Cost_{fuel})

2.39 \$/MMBtu

Reagent (Cost_{reag})

1.66 \$/gallon for a 50 percent solution of urea*

Water (Cost_{water})

0.0042 \$/gallon*

Electricity (Cost_{elect})

0.0700 \$/kWh

Ash Disposal (for coal-fired boilers only) (Cost_{ash})

39.00 \$/ton

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =

0.015

Administrative Charges Factor (ACF) =

0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost (\$/gallon)	\$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6, Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf .	
Water Cost (\$/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf .	
Electricity Cost (\$/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a .	
Fuel Cost (\$/MMBtu)	2.40	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf .	
Ash Disposal Cost (\$/ton)	48.8	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm .	
Percent sulfur content for Coal (% weight)	1.84	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/ .	
Percent ash content for Coal (% weight)	9.23	Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/ .	
Higher Heating Value (HHV) (Btu/lb)	11,841	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/ .	
Interest Rate (%)	5.5	Default bank prime rate	Used pre-COVID prime rate of 4.75

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	339	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	PSEL worksheet	604,800,000	lbs/Year
Actual Annual fuel consumption (Mactual) =	2017 actual	297,504,000	lbs/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.00	
Total System Capacity Factor (CF _{total}) =	Based on 8538 operating hours, 2017 actual	0.97	fraction
Total operating time for the SNCR (t_{op}) =	CF _{total} x 8760 =	8760	hours
NOx Removal Efficiency (EF) =	(NO _x _{in} - NO _x _{out})/NO _x _{in} =	40	percent
NOx removed per hour =	NO _x _{in} x EF x Q _B =	23.05	lb/hour
Total NO _x removed per year =	Based on 210 tpy PSEL	84	tons/year
Coal Factor (Coal _F) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO ₂ Emission rate =	(%S/100)x(64/32)*(1x10 ⁶)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.05	
Atmospheric pressure at 1382 feet above sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6] ^{5.256} x (1/144)* =	14.0	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at <https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html>.

Reagent Data:

Type of reagent used

Urea

Molecular Weight of Reagent (MW) = 60.06 g/mole

Density = 71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R) / (MW_{NOx} \times SR) =$ (where SR = 1 for NH_3 ; 2 for Urea)	104	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent} / C_{sol} =$	207	lb/hour
	$(m_{sol} \times 7.4805) / \text{Reagent Density} =$	21.8	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24 \text{ hours/day}) / \text{Reagent Density} =$	7,400	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+i)^n / (1+i)^n - 1 =$ Where n = Equipment Life and i= Interest Rate	0.0786

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B) / NPHR =$	7.5	kW/hour
Water Usage: Water consumption (q_w) =	$(m_{sol} / \text{Density of water}) \times ((C_{stored} / C_{inj}) - 1) =$	99	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent ($\Delta Fuel$) =	$Hv \times m_{reagent} \times ((1/C_{inj}) - 1) =$	0.84	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1 \times 10^6) / HHV =$	9.1	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR (SNCR _{cost}) =	\$1,695,535 in 2019 dollars
Air Pre-Heater Costs (APH _{cost})* =	\$0 in 2019 dollars
Balance of Plant Costs (BOP _{cost}) =	\$2,490,937 in 2019 dollars
Total Capital Investment (TCI) =	\$5,442,414 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs (SNCR_{cost})

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220,000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEV \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147,000 \times (B_{MW} \times HRF)^{0.42} \times ELEV \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220,000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEV \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147,000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEV \times RF$$

SNCR Capital Costs (SNCR _{cost}) =	\$1,695,535 in 2019 dollars
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Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69,000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69,000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH _{cost}) =	\$0 in 2019 dollars
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* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320,000 \times (B_{MW})^{0.33} \times (NO_x \text{ Removed}/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213,000 \times (B_{MW})^{0.33} \times (NO_x \text{ Removed}/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320,000 \times (0.1 \times Q_B)^{0.33} \times (NO_x \text{ Removed}/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213,000 \times (Q_B/NPHR)^{0.33} \times (NO_x \text{ Removed}/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP _{cost}) =	\$2,490,937 in 2019 dollars
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Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	\$426,257 in 2019 dollars
Indirect Annual Costs (IDAC) =	\$430,223 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	\$856,480 in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	\$81,636 in 2019 dollars
Annual Reagent Cost =	q _{soi} x Cost _{reag} x t _{op} =	\$317,295 in 2019 dollars
Annual Electricity Cost =	P x Cost _{elect} x t _{op} =	\$4,572 in 2019 dollars
Annual Water Cost =	q _{water} x Cost _{water} x t _{op} =	\$3,626 in 2019 dollars
Additional Fuel Cost =	ΔFuel x Cost _{fuel} x t _{op} =	\$17,570 in 2019 dollars
Additional Ash Cost =	ΔAsh x Cost _{ash} x t _{op} x (1/2000) =	\$1,557 in 2019 dollars
Direct Annual Cost =		\$426,257 in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	\$2,449 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	\$427,774 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	\$430,223 in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	\$856,480 per year in 2019 dollars
NOx Removed =	84 tons/year
Cost Effectiveness =	\$10,196 per ton of NOx removed in 2019 dollars

Table A-3. SCR Cost for Medford Biomass Boilers
Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

Industrial

What type of fuel does the unit burn?

Coal

Is the SCR for a new boiler or retrofit of an existing boiler?

Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.

1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?

339 MMBtu/hour

What is the higher heating value (HHV) of the fuel?

4,600 Btu/lb

What is the estimated actual annual fuel consumption?

297,504,000 lbs/Year

Enter the net plant heat input rate (NPHR)

10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation

1382 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned:

Bituminous

Enter the sulfur content (%S) =

0.07 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the **Cost Estimate** tab. Please select your preferred method:

- Method 1
- Method 2
- Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})

365 days

Number of days the boiler operates (t_{plant})

365 days

Inlet NO_x Emissions ($NO_{x,in}$) to SCR

lb/MMBtu (based on 0.26 lb NO_x/MMBtu steam and est. 65% efficiency)

Outlet NO_x Emissions ($NO_{x,out}$) from SCR

0.017 lb/MMBtu

Stoichiometric Ratio Factor (SRF)

0.525

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})

1

Number of catalyst layers (R_{layer})

3

Number of empty catalyst layers (R_{empty})

1

Ammonia Slip (Slip) provided by vendor

2 ppm

Volume of the catalyst layers ($Vol_{catalyst}$)

UNK Cubic feet

(Enter "UNK" if value is not known)

Flue gas flow rate ($Q_{fluegas}$)

(Enter "UNK" if value is not known)

165000 acfm

Estimated operating life of the catalyst ($H_{catalyst}$)

24,000 hours

Estimated SCR equipment life

20 Years*

Gas temperature at the SCR inlet (T)

650 °F

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Base case fuel gas volumetric flow rate factor (Q_{fuel})

484 ft³/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})

50 percent*

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

Density of reagent as stored (ρ_{stored})

71 lb/cubic feet*

Number of days reagent is stored ($t_{storage}$)

14 days

Densities of typical SCR reagents:

50% urea solution

71 lbs/ft³

29.4% aqueous NH₃

56 lbs/ft³

Select the reagent used

Urea

Enter the cost data for the proposed SCR:

Desired dollar-year

2019

CEPCI for 2019

603.1 Enter the CEPCI value for 2019

541.7

2016 CEPCI

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i)

4.75 Percent

Reagent (Cost_{reag})

1.660 \$/gallon for 50% urea*

* \$1.66/gallon is a default value for 50% urea. User should enter actual value, if known.

Electricity (Cost_{elect})

0.0700 \$/kWh

Catalyst cost (CC_{replace})

\$/cubic foot (includes removal and disposal/regeneration of existing catalyst
227.00 and installation of new catalyst)

* \$227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.

Operator Labor Rate

33.00 \$/hour (including benefits)

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Operator Hours/Day

4.00 hours/day*

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) = 0.005
 Administrative Charges Factor (ACF) = 0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost (\$/gallon)	\$1.66/gallon 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SCR Cost Development Methodology, Chapter 5, Attachment 5-3, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-3_for_cost_development_methodology.pdf	
Electricity Cost (\$/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly, Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a .	
Percent sulfur content for Coal (% weight)	1.84	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/ .	
Higher Heating Value (HHV) (Btu/lb)	11,841	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/ .	
Catalyst Cost (\$/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6 .	
Operator Labor Rate (\$/hour)	\$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6 .	
Interest Rate (Percent)	5.5	Default bank prime rate	Used pre-COVID rate of 4.75

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	339	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	PSEL worksheet	604,800,000	lbs/Year
Actual Annual fuel consumption (Mactual) =	2017 actual	297,504,000	lbs/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.00	
Total System Capacity Factor (CF _{total}) =	Based on 8538 operating hours in 2017	0.97	fraction
Total operating time for the SCR (t_{op}) =	Based on 8760 PTE	8760	hours
NO _x Removal Efficiency (EF) =	(NO _x _{in} - NO _x _{out})/NO _x _{in} =	90.0	percent
NO _x removed per hour =	NO _x _{in} x EF x Q _B =	51.87	lb/hour
Total NO _x removed per year =	Based on 210 tpy PSEL	189	tons/year
NO _x removal factor (NRF) =	EF/80 =	1.13	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	$Q_{fuel} \times Q_B \times (460 + T) / (460 + 700) n_{scr} =$	165,000	acfm
Space velocity (V_{space}) =	$q_{flue\ gas} / Vol_{catalyst} =$	118.89	/hour
Residence Time	$1 / V_{space}$	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO ₂ Emission rate =	(%S/100) x (64/32) * 1x10 ⁶ / HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.05	
Atmospheric pressure at sea level (P) =	$2116 \times [(59 - (0.00356xh) + 459.7) / 518.6]^{5.256} \times (1/144)* =$	14.0	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.50	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at <https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html>.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate) ^Y -1) , where Y = $H_{catalyst} / (t_{SCR} \times 24\ hours)$ rounded to the nearest integer	0.3180	Fraction
Catalyst volume ($Vol_{catalyst}$) =	$2.81 \times Q_B \times EF_{adj} \times Slipadj \times NOx_{adj} \times S_{adj} \times (T_{adj} / N_{scr})$	1,387.80	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas} / (16\ ft/sec \times 60\ sec/min)$	172	ft ²
Height of each catalyst layer (H_{layer}) =	$(Vol_{catalyst} / (R_{layer} \times A_{catalyst})) + 1$ (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{catalyst}$	198	ft ²
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	14.1	feet
Reactor height =	$(R_{layer} + R_{empty}) \times (7\text{ft} + h_{layer}) + 9\text{ft}$	52	feet

Reagent Data:

Type of reagent used

Urea

Molecular Weight of Reagent (MW) = 60.06 g/mole

Density = 71 lb/ft³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOX_{in} \times Q_B \times EF \times SRF \times MW_R) / MW_{NOx} =$	36	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent} / Csol =$ $(m_{sol} \times 7.4805) / \text{Reagent Density}$	71	lb/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24) / \text{Reagent Density} =$	2,600	gallons (storage needed to store a 14 day reagent supply rounded to t)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+i)^n / (1+i)^n - 1 =$ Where n = Equipment Life and i= Interest Rate	0.0786

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF) ^{0.43} = where A = (0.1 x QB) for industrial boilers.	189.84	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	\$14,242,172	in 2019 dollars
Reagent Preparation Cost (RPC) =	\$2,527,689	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	\$0	in 2019 dollars
Balance of Plant Costs (BPC) =	\$4,076,992	in 2019 dollars
Total Capital Investment (TCI) =	\$27,100,909	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEV \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (0.1 \times Q_b \times CoalF)^{0.92} \times ELEV \times RF$$

SCR Capital Costs (SCR_{cost}) =

\$14,242,172 in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564,000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564,000 \times (NOx_{in} \times Q_b \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =

\$2,527,689 in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69,000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69,000 \times (0.1 \times Q_b \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APHC) =

\$0 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529,000 \times (B_{MW} \times HRF \times CoalF)^{0.42} \times ELEV \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529,000 \times (0.1 \times Q_b \times CoalF)^{0.42} \times ELEV \times RF$$

Balance of Plant Costs (BOP_{cost}) =

\$4,076,992 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	\$394,225 in 2019 dollars
Indirect Annual Costs (IDAC) =	\$2,133,203 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	\$2,527,428 in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	\$135,505 in 2019 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op} =$	\$108,918 in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elec} \times t_{op} =$	\$116,410 in 2019 dollars
Annual Catalyst Replacement Cost =		\$33,393 in 2019 dollars
For coal-fired boilers, the following methods may be used to calculate the catalyst replacement cost.		
Method 1 (for all fuel types):	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	* Calculation Method 1 selected.
Method 2 (for coal-fired industrial boilers):	$(Q_0/NPHR) \times 0.4 \times (CoalF)^{2.9} \times (NRF)^{0.71} \times (CC_{replace}) \times 35.3$	
Direct Annual Cost =		\$394,225 in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	\$3,071 in 2019 dollars
Capital Recovery Costs (CR) =	CRF x TCI =	\$2,130,131 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	\$2,133,203 in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	\$2,527,428 per year in 2019 dollars
NOx Removed =	189 tons/year
Cost Effectiveness =	\$13,373 per ton of NOx removed in 2019 dollars

Table A-4
Boise Cascade Medford Mill
Capital and Annual Costs Associated with WESP for Dryer RTOs

CAPITAL COSTS			ANNUALIZED COSTS			
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)
Direct Costs				Direct Annual Costs		
<i>Purchased Equipment Costs</i>				<i>Operating Labor</i>		
(a) A WESP	\$ 40 per scfm	\$5,800,000	(b) Operator ^(c)	1 hours/shift	\$33.00 per hour ^(d)	\$34,906
(b) Instrumentation and controls	0.10 A	\$580,000	(b) Supervisor	15% of operator labor		\$5,236
(b) Sales Tax	0.03 A	\$174,000	(b) Coordinator	33% of operator labor		\$11,519
(b) Freight	0.05 A	\$290,000				
B Total Purchased Equipment Cost		\$6,844,000				
<i>Direct Installation Costs</i>				<i>Maintenance</i>		
(b) Foundations and Supports	0.04 B	\$273,760	(b) Maintenance labor ^(c)	0.5 hours/shift	\$60.00 per hour ^(d)	\$31,733
(b) Handling and Erection	0.50 B	\$3,422,000	(b) Maintenance materials	1% of purchased equipment costs		\$68,440
(b) Electrical	0.08 B	\$547,520				
(b) Piping	0.01 B	\$68,440				
(b) Insulation for Ductwork	0.02 B	\$136,880				
(b) Painting	0.02 B	\$136,880				
Direct Installation Cost		\$4,585,480				
Total Direct Costs		\$11,429,480				
<i>Indirect Costs</i>				<i>Utilities</i> ^(e)		
(b) Engineering	0.20 B	\$1,368,800	Electricity - unknown	kW	\$0.07 per kWh ^(d)	\$0
(b) Construction and Field Expenses	0.20 B	\$1,368,800				
(b) Contractor fees	0.10 B	\$684,400				
(b) Start-up	0.01 B	\$68,440				
(b) Performance test	0.01 B	\$68,440				
(b) Model Study	0.02 B	\$136,880				
(b) Contingencies	0.03 B	\$205,320				
Total Indirect Costs		\$3,901,080				
Total Capital Investment (TCI)		\$15,330,560	Cost Effectiveness (\$/ton)			
			PM ₁₀ Control Efficiency ^(f) : 99.0%			
			PM ₁₀ PSEL: 60 tpy			
			Controlled PM ₁₀ Emissions: 59 tons of PM ₁₀ removed annually			
			Total Annual Costs/Controlled PM ₁₀ Emissions: \$34,686			

^(a) Wet electrostatic precipitator (WESP) capital cost based on low end of the range provided in the EPA fact sheet, which indicates capital cost of a wet ESP ranges from \$40 to \$200 per scfm. Combined flow rate from the RTOs is 145,000 scfm. <https://www3.epa.gov/trc/catc/dir1/wespwp1.pdf> Capital cost is consistent with cost for WESPs on dryers obtained by EPA for the PCWP MACT ICR.

^(b) Cost information estimated based on the U.S. EPA OAQPS Control Cost Manual, Section 6, Chapter 3, September 1999.

^(c) Based on 2017 operating hours.

^(d) Facility-specific cost.

^(e) The electricity requirement for a new WESP is not known.

^(f) Assumes installation of a WESP after the existing control equipment will achieve an additional 99% reduction in PM₁₀ emissions. The estimated reduction is likely high because actual emissions are much lower than the PSEL.

**APPENDIX B -
2017 ACTUAL EMISSIONS**

Medford Mill Reported 2017 Actual Emissions

Source ID	Source	Control Technology or Technique Used	Fugitive Source? (Y/N)	2017 Actual Emissions, tpy		
				PM ₁₀	SO ₂	NO _x
EU1	Biomass boilers (3)	ESP	N	24	15	105
EU2	Veneer Dryers	2 RTOs	N	81.5	0.1	8.4
EU3a	Presses 1, 2, 3 & 4	None	Y	16	--	--
EU3b	Press 5 & future presses	None	Y	-	--	--
EU5a	BH C	Baghouse	N	0.9	--	--
EU5b	BH E, F & G	Baghouse	N	0.8	--	--
EU506	Material Handling	Watering as needed	Y	0.04	--	--
EU508	Unpaved Roads	Facility-wide speed limit	Y	1.1	--	--



eurofins

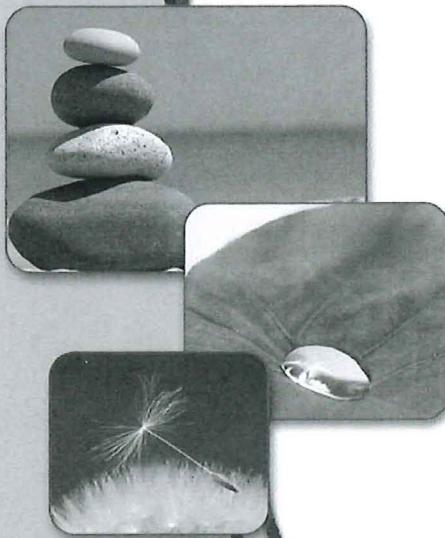
Environment Testing
America

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ANALYTICAL REPORT

Eurofins TestAmerica, Seattle
5755 8th Street East
Tacoma, WA 98424
Tel: (253)922-2310

Laboratory Job ID: 580-94493-1
Client Project/Site: Willamina Washpad or Oaks

For:
LPG Associates, Inc.
122 6th Street
Lake Oswego, Oregon 97034

Attn: Frank Jones

M. Elaine Walker

Authorized for release by:
5/19/2020 1:19:36 PM
Elaine Walker, Project Manager II
(253)248-4972
elaine.walker@testamericainc.com
Designee for
Nathan Lewis, Project Manager I
(253)922-2310
nathan.lewis@testamericainc.com

LINKS

Review your project
results through

Total Access

Have a Question?



Visit us at:

www.eurofinsus.com/Env

This report has been electronically signed and authorized by the signatory. Electronic signature is intended to be the legally binding equivalent of a traditionally handwritten signature.

Results relate only to the items tested and the sample(s) as received by the laboratory.

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Case Narrative

Client: LPG Associates, Inc.
Project/Site: Willamina Washpad or Oaks

Job ID: 580-94493-1

Job ID: 580-94493-1

Laboratory: Eurofins TestAmerica, Seattle

Narrative

Job Narrative 580-94493-1

Receipt

One sample was received on 5/6/2020 11:45 AM; the sample arrived in good condition, properly preserved and, where required, on ice. The temperature of the cooler at receipt was 3.0° C.

Metals

No analytical or quality issues were noted, other than those described in the Definitions/Glossary page.

General Chemistry

No analytical or quality issues were noted, other than those described in the Definitions/Glossary page.

Definitions/Glossary

Client: LPG Associates, Inc.
Project/Site: Willamina Washpad or Oaks

Job ID: 580-94493-1

Qualifiers

Metals	Qualifier	Qualifier Description
	F1	MS and/or MSD recovery exceeds control limits.
	J	Result is less than the RL but greater than or equal to the MDL and the concentration is an approximate value.

Glossary

Abbreviation	These commonly used abbreviations may or may not be present in this report.
n	Listed under the "D" column to designate that the result is reported on a dry weight basis
%R	Percent Recovery
CFL	Contains Free Liquid
CNF	Contains No Free Liquid
DER	Duplicate Error Ratio (normalized absolute difference)
Dil Fac	Dilution Factor
DL	Detection Limit (DoD/DOE)
DL, RA, RE, IN	Indicates a Dilution, Re-analysis, Re-extraction, or additional Initial metals/anion analysis of the sample
DLC	Decision Level Concentration (Radiochemistry)
EDL	Estimated Detection Limit (Dioxin)
LOD	Limit of Detection (DoD/DOE)
LOQ	Limit of Quantitation (DoD/DOE)
MDA	Minimum Detectable Activity (Radiochemistry)
MDC	Minimum Detectable Concentration (Radiochemistry)
MDL	Method Detection Limit
ML	Minimum Level (Dioxin)
MQL	Method Quantitation Limit
NC	Not Calculated
ND	Not Detected at the reporting limit (or MDL or EDL if shown)
PQL	Practical Quantitation Limit
QC	Quality Control
RER	Relative Error Ratio (Radiochemistry)
RL	Reporting Limit or Requested Limit (Radiochemistry)
RPD	Relative Percent Difference, a measure of the relative difference between two points
TEF	Toxicity Equivalent Factor (Dioxin)
TEQ	Toxicity Equivalent Quotient (Dioxin)

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Client Sample Results

Client: LPG Associates, Inc.
Project/Site: Willamina Washpad or Oaks

Job ID: 580-94493-1

Client Sample ID: Washpad

Lab Sample ID: 580-94493-1

Date Collected: 05/05/20 07:00

Matrix: Water

Date Received: 05/06/20 11:45

Method: 6020B - Metals (ICP/MS) - Total Recoverable

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Copper	0.0024		0.0020	0.00060	mg/L		05/12/20 07:12	05/12/20 15:22	1
Lead	0.00020	J		0.00080	mg/L		05/12/20 07:12	05/12/20 15:22	1
Zinc	0.020			0.0070	mg/L		05/12/20 07:12	05/12/20 15:22	1

General Chemistry

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
HEM (Oil & Grease)	ND		5.1	5.1	mg/L		05/13/20 12:54	05/13/20 15:37	1

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Eurofins TestAmerica, Seattle

QC Sample Results

Client: LPG Associates, Inc.

Project/Site: Willamina Washpad or Oaks

Job ID: 580-94493-1

Method: 6020B - Metals (ICP/MS)

Lab Sample ID: MB 580-328108/7-A

Matrix: Water

Analysis Batch: 328187

Analyte	MB	MB	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
	Result	Qualifier							
Copper	ND		0.0020	0.00060	mg/L		05/12/20 07:12	05/12/20 15:19	1
Lead	ND		0.00080	0.00020	mg/L		05/12/20 07:12	05/12/20 15:19	1
Zinc	ND		0.0070	0.0019	mg/L		05/12/20 07:12	05/12/20 15:19	1

Lab Sample ID: LCS 580-328108/8-A

Matrix: Water

Analysis Batch: 328187

Analyte	Spike Added	LCSD	LCSD	Unit	D	%Rec	Limits	%Rec.
		Result	Qualifier					
Copper	1.00	1.07		mg/L		107	80 - 120	
Lead	1.00	1.01		mg/L		101	80 - 120	
Zinc	1.00	1.07		mg/L		107	80 - 120	

Lab Sample ID: LCSD 580-328108/9-A

Matrix: Water

Analysis Batch: 328187

Analyte	Spike Added	LCSD	LCSD	Unit	D	%Rec	Limits	RPD	Limit
		Result	Qualifier						
Copper	1.00	1.07		mg/L		107	80 - 120	0	20
Lead	1.00	1.01		mg/L		101	80 - 120	1	20
Zinc	1.00	1.07		mg/L		107	80 - 120	0	20

Lab Sample ID: 580-94620-D-1-C MS

Matrix: Water

Analysis Batch: 328187

Analyte	Sample	Sample	Spike	MS	MS	Unit	D	%Rec	Limits
	Result	Qualifier	Added	Result	Qualifier				
Copper	0.016		1.00	1.14		mg/L		112	80 - 120
Lead	0.00072	J	1.00	0.968		mg/L		97	80 - 120
Zinc	0.066	F1	1.00	1.34	F1	mg/L		127	80 - 120

Lab Sample ID: 580-94620-D-1-D MSD

Matrix: Water

Analysis Batch: 328187

Analyte	Sample	Sample	Spike	MSD	MSD	Unit	D	%Rec	Limits
	Result	Qualifier	Added	Result	Qualifier				
Copper	0.016		1.00	1.19		mg/L		117	80 - 120
Lead	0.00072	J	1.00	0.988		mg/L		99	80 - 120
Zinc	0.066	F1	1.00	1.37	F1	mg/L		131	80 - 120

Lab Sample ID: 580-94620-D-1-B DU

Matrix: Water

Analysis Batch: 328187

Analyte	Sample	Sample	Spike	DU	DU	Unit	D	RPD	Limit
	Result	Qualifier	Added	Result	Qualifier				
Copper	0.016			0.0157		mg/L		3	20
Lead	0.00072	J		0.000710	J	mg/L		2	20
Zinc	0.066	F1		0.0641		mg/L		2	20

Client Sample ID: Duplicate

Prep Type: Total Recoverable

Prep Batch: 328108

Eurofins TestAmerica, Seattle

QC Sample Results

Client: LPG Associates, Inc.
Project/Site: Willamina Washpad or Oaks

Job ID: 580-94493-1

Method: 1664A - HEM and SGT-HEM

Lab Sample ID: MB 580-328236/1-A

Matrix: Water

Analysis Batch: 328260

MB	MB												
Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac				
HEM (Oil & Grease)	ND		5.0	5.0	mg/L		05/13/20 12:54	05/13/20 15:37	1				

Lab Sample ID: LCS 580-328236/2-A

Matrix: Water

Analysis Batch: 328260

MB	MB												
Analyte	Spike	LCS	LCS										
HEM (Oil & Grease)	Added	Result	Qualifier	Unit	D	%Rec.	Limits						

Lab Sample ID: LCSD 580-328236/3-A

Matrix: Water

Analysis Batch: 328260

MB	MB												
Analyte	Spike	LCSD	LCSD										
HEM (Oil & Grease)	Added	Result	Qualifier	Unit	D	%Rec.	Limits	RPD	Limit	RPD	Limit		

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Lab Chronicle

Client: LPG Associates, Inc.
Project/Site: Willamina Washpad or Oaks

Job ID: 580-94493-1

Client Sample ID: Washpad

Lab Sample ID: 580-94493-1

Date Collected: 05/05/20 07:00

Matrix: Water

Date Received: 05/06/20 11:45

Prep Type	Batch	Batch	Run	Dilution Factor	Batch	Prepared	Analyst	Lab
	Type	Method			Number	or Analyzed		
Total Recoverable	Prep	3005A			328108	05/12/20 07:12	A1B	TAL SEA
Total Recoverable	Analysis	6020B		1	328187	05/12/20 15:22	FCW	TAL SEA
Total/NA	Prep	1664A			328236	05/13/20 12:54	FCG	TAL SEA
Total/NA	Analysis	1664A		1	328260	05/13/20 15:37	FCG	TAL SEA

Laboratory References:

TAL SEA = Eurofins TestAmerica, Seattle, 5755 8th Street East, Tacoma, WA 98424, TEL (253)922-2310

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Accreditation/Certification Summary

Client: LPG Associates, Inc.

Project/Site: Willamina Washpad or Oaks

Job ID: 580-94493-1

Laboratory: Eurofins TestAmerica, Seattle

The accreditations/certifications listed below are applicable to this report.

Authority	Program	Identification Number	Expiration Date
Oregon	NELAP	WA100007	11-06-20

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Sample Summary

Client: LPG Associates, Inc.
Project/Site: Willamina Washpad or Oaks

Job ID: 580-94493-1

Lab Sample ID	Client Sample ID	Matrix	Collected	Received	Asset ID
580-94493-1	Washpad	Water	05/05/20 07:00	05/06/20 11:45	

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Chain of Custody Record

TestAmerica Laboratories, Inc.

Regulatory Program: <input type="checkbox"/> DW <input checked="" type="checkbox"/> NPDES <input type="checkbox"/> RCRA <input type="checkbox"/> Other:																	
Client Contact			Project Manager: Frank Jones			Site Contact: Bob Borgen			Date: 5-5-20								
LPG Associates 122 6th St. Lake Oswego, OR 97034 (503) 230-1240 Phone (503) 895-0445 FAX Project Name: 1173 Willamina Washpad Site: P O #			Tel/Fax: (503) 230-1240			Lab Contact:			Carrier:								
Analysis Turnaround Time																	
<input type="checkbox"/> CALENDAR DAYS <input type="checkbox"/> WORKING DAYS TAT if different from Below _____ <input checked="" type="checkbox"/> 2 weeks <input type="checkbox"/> 1 week <input type="checkbox"/> 2 days <input type="checkbox"/> 1 day																	
Sample Identification			Sample Date	Sample Time	Sample Type (C=Comp, G=Grab)	Matrix	# of Cont.	Filtered Sample (Y/N)	Perform MS/MSD (Y/N)	Oil & Grease by EPA 1664	Lead, Copper, Zinc by EPA 6020	Sample Specific Notes:					
Washpad			5-5-20	7:00 AM	G	W	2	N N	X								
Washpad			5-5-20	7:02 AM	G	W	1	N N	X								
Preservation Used: 1=Ice, 2=HCl, 3=H ₂ SO ₄ , 4=HNO ₃ , 5=NaOH, 6=Other																	
Possible Hazard Identification: Are any samples from a listed EPA Hazardous Waste? Please List any EPA Waste Codes for the sample in the Comments Section if the lab is to dispose of the sample.																	
Sample Disposal (A fee may be assessed if samples are retained longer than 1 month) <input checked="" type="checkbox"/> Return to Client <input type="checkbox"/> Disposal by Lab <input type="checkbox"/> Archive for _____ Months																	
Special Instructions/QC Requirements & Comments:																	
Custody Seals Intact: <input type="checkbox"/> Yes <input type="checkbox"/> No			Custody Seal No.:			Cooler Temp. (°C): Obs'd: <u>32</u> Corr'd: _____			Therm ID No.:								
Relinquished by: <u>Sandra V. Asquer</u>			Company: <u>Big Cascade, Willamina</u>			Date/Time: <u>5-5-20 7:00</u>			Received by: <u>SC000</u>			Company: <u>TAOR</u>			Date/Time: <u>5-5-20 445</u>		
Relinquished by:			Company:			Date/Time:			Received by:			Company:			Date/Time:		
Relinquished by:			Company:			Date/Time:			Received in Laboratory by:			Company:			Date/Time:		

Form No. CA-C-WI-002, Rev. 4.11, dated 1/24/2017

TestAmerica Portland
8920 SW Gemini Dr (Building 7)

Beaverton, OR 97008-7123
phone 503.906.9200 fax 503.906.9210

Chain of Custody Record

TestAmerica
THE LEADER IN ENVIRONMENTAL TESTING

TestAmerica Laboratories, Inc.

Regulatory Program: DW NPDES RCRA Other:

Client Contact		Project Manager: Frank Jones			Site Contact: Bob Bury		Date: 5-5-20		COC No:	
LPG Associates 122 6th St. Lake Oswego, OR 97034 (503) 230-1240 Phone (503) 895-0445 FAX Project Name: 1173 Willamina Washpad Site: P O #		Tel/Fax: (503) 230-1240			Lab Contact:		Carrier:		1 of 1 COCs	
Analysis Turnaround Time		<input type="checkbox"/> CALENDAR DAYS <input type="checkbox"/> WORKING DAYS TAT if different from Below _____ <input checked="" type="checkbox"/> 2 weeks <input type="checkbox"/> 1 week <input type="checkbox"/> 2 days <input type="checkbox"/> 1 day			Filtered Sample (Y/N) Perform MS / MSD (Y/N) Oil & Grease by EPA 1664 Lead, Copper, Zinc by EPA 6020				Sampler:	
									For Lab Use Only:	
									Walk-in Client: _____	
									Lab Sampling: _____	
									Job / SDG No.: _____	
Sample Identification		Sample Date	Sample Time	Sample Type (C=Comp, G=Grab)	Matrix	# of Cont.			Sample Specific Notes:	
Washpad		5-5-20	7:02 AM	G	W	2	N N X			
Washpad		5-5-20	7:02 AM	G	W	1	N N X			
 580-94493 Chain of Custody										
Preservation Used: <input type="checkbox"/> 1=Ice <input type="checkbox"/> 2=HCl <input type="checkbox"/> 3=H2SO4 <input type="checkbox"/> 4=HNO3 <input type="checkbox"/> 5=NaOH <input type="checkbox"/> 6=Other		2		3		4		5		
Possible Hazard Identification: Are any samples from a listed EPA Hazardous Waste? Please List any EPA Waste Codes for the sample in the Comments Section if the lab is to dispose of the sample.										
<input checked="" type="checkbox"/> Non-Hazard <input type="checkbox"/> Flammable <input type="checkbox"/> Skin Irritant <input type="checkbox"/> Poison B <input type="checkbox"/> Unknown										
Sample Disposal (A fee may be assessed if samples are retained longer than 1 month)										
<input type="checkbox"/> Return to Client <input checked="" type="checkbox"/> Disposal by Lab <input type="checkbox"/> Archive for _____ Months										
Special Instructions/QC Requirements & Comments:										
Custody Seals Intact: <input type="checkbox"/> Yes <input type="checkbox"/> No		Custody Seal No.:		Cooler Temp. (°C): Obs'd: <u>25</u>		Corrd:		Therm ID No.:		
Relinquished by: <u>Sandy VASQUEZ</u>		Company: <u>BEN CALAIS, Willamina</u>		Date/Time: <u>5-5-20 7:02</u>		Received by: <u>Bob</u>		Company: <u>TARON</u>		
Relinquished by: <u>Bob</u>		Company: <u>TARON</u>		Date/Time: <u>5/6/20 10:00</u>		Received by: <u>Bob</u>		Company: <u>TARON</u>		
Relinquished by: <u>Bob</u>		Company: <u></u>		Date/Time: <u></u>		Received in Laboratory by: <u></u>		Company: <u></u>		

pH 6.91

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Form No. CA-C-WI-002, Rev. 4.11, dated 1/24/2017
5/19/2020

126 = 0.8
0.4

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Login Sample Receipt Checklist

Client: LPG Associates, Inc.

Job Number: 580-94493-1

Login Number: 94493

List Source: Eurofins TestAmerica, Seattle

List Number: 1

Creator: O'Connell, Jason I

Question	Answer	Comment
Radioactivity wasn't checked or is </= background as measured by a survey meter.	True	
The cooler's custody seal, if present, is intact.	True	
Sample custody seals, if present, are intact.	True	
The cooler or samples do not appear to have been compromised or tampered with.	True	
Samples were received on ice.	True	
Cooler Temperature is acceptable.	True	
Cooler Temperature is recorded.	True	
COC is present.	True	
COC is filled out in ink and legible.	True	
COC is filled out with all pertinent information.	True	
Is the Field Sampler's name present on COC?	False	
There are no discrepancies between the containers received and the COC.	True	
Samples are received within Holding Time (excluding tests with immediate HTs)	True	
Sample containers have legible labels.	True	
Containers are not broken or leaking.	True	
Sample collection date/times are provided.	True	
Appropriate sample containers are used.	True	
Sample bottles are completely filled.	True	
Sample Preservation Verified.	True	
There is sufficient vol. for all requested analyses, incl. any requested MS/MSDs	True	
Containers requiring zero headspace have no headspace or bubble is <6mm (1/4").	True	
Multiphasic samples are not present.	True	
Samples do not require splitting or compositing.	True	
Residual Chlorine Checked.	N/A	

